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APPARATUS AND METHODS FOR INSTALLING INSTRUMENTATION LINE IN A WELLBORE

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APPARATUS AND METHODS FOR INSTALLING INSTRUMENTATION LINE IN A WELLBORE

BACKGROUND OF THE INVENTION

Field of the Invention

[0001] The invention generally relates to methods and apparatus for connecting instrumentation lines in a wellbore. More particularly, the invention provides methods and apparatus for delivering a fiber optic cable to a selected depth within a hydrocarbon wellbore.

Description of the Related Art

[0002] In a typical oil or gas well, a borehole drilled into the surface of the earth extends downward into a formation to provide a wellbore. The wellbore may include any number of tubular strings such as a string of surface casing cemented into place and a liner string hung off of the casing that extends into a producing zone, or pay zone, where the liner is perforated to permit inflow of hydrocarbons into the bore of the liner. Alternatively, the wellbore may be completed as an open hole which may include a sand screen positioned at the end of the casing to support the formation and filter hydrocarbons that pass therethrough. During the life of the well, it is sometimes desirable to monitor conditions *in situ*. Recently, technology has enabled well operators to monitor conditions within a wellbore by installing permanent monitoring systems downhole. The monitoring systems permit the operator to monitor such parameters as multiphase fluid flow, as well as pressure and temperature. Downhole measurements of pressure, temperature and fluid flow play an important role in managing oil and gas or other sub-surface reservoirs.

[0003] Historically, permanent monitoring systems have used electronic components to provide pressure, temperature, flow rate and water fraction data on a real-time basis. These monitoring systems employ temperature gauges, pressure gauges, acoustic sensors, and other instruments, or "sondes," disposed within the wellbore. Such electrical instruments are either battery operated, or are powered by electrical cables deployed from the surface. Typically, conductive electrical cables transmit the electrical signals from the electronic sensors back to the surface.

[0004] Recently, optical sensors have been developed which communicate readings from the wellbore to optical signal processing equipment located at the surface. The optical sensors may be variably located within the wellbore and do not require an electrical line from the surface. For example, optical sensors may be positioned in fluid communication with the housing of a submersible electrical pump. Such an arrangement is taught in U.S. Patent No. 5,892,860, issued to Maron, *et al.*, in 1999. The '860 patent is incorporated herein in its entirety, by reference. Optical sensors may also be disposed along the tubing within a wellbore to sense the desired parameters. As another example of an optical sensor, a distributed temperature sensor system is a known measurement technique that provides a continuous temperature profile along the entire length of an optical fiber. Distributed temperature sensor systems operate on the principle of backscattering, the known velocity of light and the thermal energy in the optical fiber. Regardless of the type of optical sensor, an optical waveguide or fiber optic cable runs from the surface to the optical sensor downhole. Surface equipment transmits optical signals to the downhole optical sensors via the fiber optic cables which transmit return optical signals to an optical signal processor at the surface.

[0005] Therefore, both optical and electronic sensors often require an instrumentation line such as a fiber optic cable, a wire or a conductive electric cable that runs down the wellbore to the sensor. The instrumentation line may run down the outer surface of one of the tubular strings in the wellbore such as production tubing and clamp thereto at intervals as is known in the art. When the instrumentation line is on the outside of a liner or sand screen, the instrumentation line may be subjected to trauma or damage as the liner or sand screen runs into the wellbore. Trauma further increases where the instrumentation line is disposed along the outer surface of an expanded liner or sand screen since the instrumentation line compresses between the outer surface of the liner or sand screen and the surrounding formation.

[0006] Further, the instrumentation line may be exposed to the harsh effects of chemicals used in well completion or remediation operations. For example, it is

oftentimes desirable to wash the tubing in order to remove grease and contaminants during a last stage in well completion. This is accomplished by circulating acid through the tubing. In addition, an acid wash or other stimulant may clean the sand screen and tubing of paraffins, hydrates and scale that accumulate along the sand screen and tubing during the life of a producing well. The application of such chemicals may be detrimental to the integrity of the instrumentation line. This is particularly true where the instrumentation line is a fiber optic cable of a distributed temperature sensor system. A packer may isolate an upper section of the instrumentation line from the chemicals used in the well completion or remediation operations such that only a lower section of the instrumentation line is subject to the harsh chemicals.

[0007] The expandable sand screen may include protective features that help protect the instrumentation line disposed along the outside of the sand screen as the sand screen is run and expanded. For example, the instrumentation line may pass along a recess in the outer diameter of the sand screen. Arrangements for the recess are described more fully in the pending application entitled "Profiled Recess for Instrumented Expandable Components," having Serial No. 09/964,034, which is incorporated herein in its entirety, by reference. Alternatively, a specially profiled encapsulation around the sand screen which contains arcuate walls may house the instrumentation line. Arrangements for the encapsulation are described more fully in the pending application entitled "Profiled Encapsulation for Use with Expandable Sand Screen," having Serial No. 09/964,160, which is also incorporated herein in its entirety, by reference. However, these protective features fail to protect the instrumentation line from the chemicals used during well completion and remediation operations. With the instrumentation line clamped to a liner or sand screen and/or disposed in a protective feature of a sand screen, it is not possible to pull the instrumentation line during an acid wash or other remedial operation, at least not without pulling the tubular and/or sand screen.

[0008] Therefore, there exists a need for a method of installing an instrumentation line into a wellbore after expansion of a sand screen or other liner,

after setting of a packer, and/or after conducting an acid wash. Further, a need exists for a coupling apparatus that permits a lower instrumentation line to connect downhole with an upper instrumentation line after the upper instrumentation line is placed in the wellbore. There exists a further need for a coupling apparatus that allows the lower instrumentation line to be detached and removed from the wellbore without removing the upper instrumentation line.

SUMMARY OF THE INVENTION

[0009] The invention provides a coupler and a method for installing an instrumentation line, such as fiber optic cable, into a wellbore. The coupler places upper and lower instrumentation lines in communication with one another downhole to form a single line. The apparatus comprises a landing tool and a stinger that lands on the landing tool, thereby placing the upper and the lower instrumentation lines in communication. The landing tool is run into the wellbore at the lower end of a tubular, such as production tubing. The upper instrumentation line affixes to the tubing and landing tool and extends to the surface. The lower instrumentation line affixes along the stinger. In this manner, the lower instrumentation line may be installed after expansion of a well screen or liner and may be later removed from the wellbore prior to well workover procedures without pulling the production string.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

[0011] Figure 1 is a partial sectional view of a wellbore having a coupler that includes a landing tool at the end of a tubular string and a stinger landed in the landing tool.

[0012] Figure 2 is a partial sectional view of the landing tool in a run-in position.

[0013] Figure 2A is an enlarged partial sectional view of a portion of the landing tool of Figure 2.

[0014] Figure 3 is a perspective view in partial section of a connector guide of the landing tool that houses a connector for an upper instrumentation line.

[0015] Figure 4 is a perspective view of an upper portion of an orienting sleeve of the landing tool.

[0016] Figure 5 is a partial sectional view of the stinger.

[0017] Figure 5A is an enlarged sectional view of a portion of the stinger shown in Figure 5.

[0018] Figure 6 is a partial sectional view of the coupler in an intermediate position with the stinger partially within the landing tool.

[0019] Figures 6A and 6B are enlarged partial sectional views of the coupler shown in Figure 6 in the intermediate position.

[0020] Figure 7 is a cross section view of the coupler across line 7-7 in Figure 6A.

[0021] Figure 8 is a partial sectional view of the coupler in a connected position with the stinger landed within the landing tool.

[0022] Figure 9 is a cross section view of the coupler across line 9-9 in Figure 8.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0023] **Figure 1** illustrates a partial sectional view of an exemplary wellbore **50** that may receive a coupler **100** of the invention. While the coupler **100** is shown generally in **Figure 1**, the detail of the coupler **100** will be described in detail with reference to the various figures hereinafter. The wellbore **50** includes a string of

casing **20** secured within a surrounding earth formation **25** by cement **30**, a tubular string such as production tubing **35** run into the casing **20**, an instrumentation line **12** and a packer **40** that seals the annular region **45** between the tubing **35** and the surrounding casing **20**. The wellbore **50** is completed with a screen hanger **60** that supports a sand screen **65** adjacent a desired pay zone **55**. As shown, the coupler **100** connects to the tubing **35** by a flow sub **70**. The flow sub **70** includes perforations **75** that permit the inflow of hydrocarbons for production and the circulation of chemicals around the coupler **100** during later well completion or remediation operations.

[0024] The instrumentation line **12** includes an upper instrumentation line **12U** and a lower instrumentation line **12L**. The instrumentation lines **12U**, **12L** may be an electrical line, an optical waveguide or a cable comprised of both optical fibers and electrical wires. Where the instrumentation lines **12U**, **12L** are fiber optic lines, the lines **12U**, **12L** may be part of a distributed temperature sensor system, a pressure and temperature sensor system, a flow meter, an acoustic sensor system, a chemical sensor, a seismic sensor or any other type of sensor or system including combinations thereof. In any case, the lower instrumentation line **12L** is recoverably delivered to the depth of the pay zone **55** such that the line **12L** extends to a level within the wellbore **50** below the packer **40** and adjacent the sand screen **65**. The upper instrumentation line **12U** runs along the tubing **35** to the surface and is connected to surface instrumentation **132**.

[0025] The invention is directed to the coupler **100** and a method for using the coupler **100**. The coupler **100** places the upper **12U** and lower **12L** instrumentation lines in communication with one another, thereby forming the single instrumentation line **12**. However, the operator may remove the lower instrumentation line **12L** from the wellbore **50** at any time after the coupler **100** has placed the upper and lower instrumentation lines **12U**, **12L** in communication. In this manner, the lower portion **12L** of the instrumentation line **12** is spared trauma from later remediation or well workover procedures. Therefore, the wellbore completion arrangement shown in **Figure 1** is for exemplary purposes only. The invention is not limited as to the

manner of completing the well, and the coupler **100** may be employed in any open hole completion, cased hole completion, injection well, lateral well, horizontal well or other known or contemplated wells as can be appreciated by one skilled in the art.

[0026] The coupler **100** comprises a landing tool **200** and a stinger **300** that are connected to one another downhole. In operation, the landing tool **200** is disposed at the lower end of the tubing **35**, and the upper instrumentation line **12U** connects to the landing tool **200** and runs into the wellbore **50** with the tubing **35** and landing tool **200**. The lower instrumentation line **12L** connects to the stinger **300**. The stinger **300** releasably couples to a working string such as coiled tubing string (not shown) and runs into the wellbore **50** on the working string after the tubing **35** and landing tool **200** are in place. In this manner, the stinger **300** lands on the landing tool **200** as shown in **Figure 1** to bring the upper and lower instrumentation lines **12U**, **12L** together and provide the instrumentation line **12** as will be explained more fully hereinafter. Thereafter, the working string releases from the stinger **300** and the working string is removed from the wellbore **50**. As shown, the length of the stinger **300** that extends from the landing tool **200** may be selected such that lower instrumentation line **12L** that is attached to the stinger **300** is positioned at the desired depth within the wellbore **50**.

[0027] **Figure 2** shows a partial section view of a portion of the landing tool **200** of the coupler **100** in a run-in position. The landing tool **200** includes a series of tubular subs connected by threads or otherwise in order to form an elongated tubular body. As shown in **Figure 8** with the landing tool **200** and stinger **300** of the coupler **100** in the connected position, the landing tool **200** receives a portion of the stinger **300** within the bore of the elongated tubular body. A landing profile **236** located on the inner diameter of the landing tool **200** mates with a corresponding landing shoulder **366** of the stinger **300** to limit movement of the stinger **300** through the landing tool **200**. One of the tubular subs of the landing tool **200** is an offset mandrel **210** having an enlarged outer diameter portion **216**. The landing tool **200** may include additional tubular subs or a combination of one or more of the subs shown integrated into a single sub depending upon the manufacturing protocol. In

the arrangement shown in **Figure 2**, the landing tool **200** includes several subs in addition to the offset mandrel **210**. For example, the landing tool **200** may include an upper locking sub **220** having a profile **226** along its inner diameter for receiving locking dogs **426** of an optional latching mechanism **400** of the stinger **300** as shown in **Figure 8**.

[0028] An orienting sleeve **280** shown disposed within the offset mandrel **210** of the landing tool **200** is rotationally fixed within the offset mandrel **210**. Preferably, the orienting sleeve **280** threads into the inner diameter of the offset mandrel **210**. In the arrangement shown in **Figure 2**, the lower end of the orienting sleeve **280** threads down onto a shoulder along the inner diameter of the offset mandrel **210**. However, a weld or other connection may be provided. The orienting sleeve **280** provides proper rotational orientation for the stinger **300** as the stinger **300** lands into the landing tool **200**. To this end, the upper end of the orienting sleeve **280** includes an orienting shoulder **286** that receives a key **388** of the stinger **300** when in the connected position shown in **Figure 8**. In one arrangement, the orienting shoulder **286** is helical. **Figure 4** provides a prospective view of the top portion of the orienting sleeve **280** with the helical orienting shoulder **286**. The orienting shoulder **286** includes a bottom-out edge **288** into which the key **388** of the stinger **300** is guided.

[0029] Referring to **Figure 2A**, the enlarged outer diameter portion **216** of the offset mandrel **210** includes a debris sleeve **250** and a pocket **218** that houses a bow spring **290**. The pocket **218** of the landing tool **200** houses an upper connector **270** within a connector guide **278** in the run-in position. The upper connector **270** connects to the lower end of the upper instrumentation line **12U**. While only the lowest portion of the upper instrumentation line **12U** is shown, it is understood that the line **12U** runs to the surface. In the run-in position for the landing tool **200**, the upper end of the debris sleeve **250** shoulders against a debris sleeve shoulder **219** along the inner diameter of the offset mandrel **210**. However, the debris sleeve **250** is slideable along the inner diameter of the offset mandrel **210**. The debris sleeve **250** includes a window **256** milled in a wall thereof. As the debris sleeve **250** is

pushed downward during operation relative to the offset mandrel **210**, the window **256** in the debris sleeve **250** moves adjacent the offset mandrel pocket **218**. This serves to expose the connector **270** for the upper instrumentation line **12U** to the inner bore **205** of the offset mandrel **210**. This, in turn, allows the bow spring **290** to act against the connector guide **278** and urge the connector **270** through the window **256** of the debris sleeve **250** in order to align with the mating connector **370** of the stinger **300**. For other embodiments, hydraulic force through coiled tubing, or other type of force, may also be used to urge the connector guide **278** inwardly toward the lower connector **370** of the stinger **300**.

[0030] **Figure 3** shows a perspective view of the connector guide **278** apart from the offset mandrel **210**. The connector guide **278** includes an opening **275** for receiving the lower end of the upper instrumentation line **12U** (not shown) and at least a portion of the connector **270** (not shown). The connector guide **278** also includes a pair of pin grooves **273**. As will be discussed in greater detail below, the opposing pin grooves **273** receive pins **373** within the debris sleeve **250** as shown in **Figure 9**. As the bow spring **290** urges the connector guide **278** inwardly towards the bore **205** of the offset mandrel **210**, the pins **373** mate with the pin grooves **273** to align the connector guide **278** and housed upper connector **270** with a lower connector **370** in the stinger **300**.

[0031] Referring back to **Figure 2A**, the debris sleeve **250** includes an upper snap ring **251**, a lower snap ring **253** and an optional pair of debris wipers **255**. In the run-in position shown in **Figure 2A**, the upper snap ring **251** resides within a snap ring profile **211** along the offset mandrel **210** and the lower snap ring **253** resides closely around the debris sleeve **250**. Both the upper and lower snap rings **251, 253** are biased outward. Therefore, the bias of the upper snap ring **251** maintains the upper snap ring **251** within the snap ring profile **211** until forced inwardly when sufficient force is applied against the top of the debris sleeve **250**, thereby releasing the debris sleeve **250** from its axial location within the offset mandrel **210**. This, in turn, permits the debris sleeve **250** to slide downwardly within the inner diameter of the offset mandrel **210**. Thus, once the debris sleeve slides

downward, the lower snap ring **253** expands into a lower snap ring profile **213** (shown in **Figure 2**) along the offset mandrel **210**. The debris wipers **255** essentially define elastomeric (or other pliable material) seals disposed circumferentially around the debris sleeve **250**. The debris wipers **255** are placed at opposite ends of the window **256**, and serve to keep debris from entering the window **256** and the pocket **218** of the offset mandrel **210**.

[0032] **Figure 5** illustrates a partial sectional view of a portion of the stinger **300** of the coupler **100** as shown in **Figure 1** and **Figure 8**. As with the landing tool **200**, the stinger **300** generally defines an elongated tubular body that includes a series of subs connected end-to-end. As shown, the stinger **300** includes subs such as a connector mandrel **310**, a collet mandrel **330**, a no-go sub **360**, and at least one stinger sub **390** that connect to a lower end of one another successively by threads or otherwise. The connector mandrel **310** has an outer diameter dimensioned to be closely received within the inner diameter of both the orienting sleeve **280** and the debris sleeve **250** of the landing tool **200** as shown in **Figure 8**. Disposed along the outer diameter of the connector mandrel **310** is the key **388**. The key **388** represents a fixed protrusion that catches the orienting shoulder **286** of the orienting sleeve **280** when the stinger **300** is lowered into the landing tool **200**. Also visible in **Figure 5** is the landing shoulder **366** for landing in the landing profile **236** of the landing tool **200** as described above. A no-go collar attached to the upper end of the no-go sub **360** serves as the shoulder **366** for the stinger **300**.

[0033] The stinger subs **390** define an elongated tubular body that extends downward into the pay zone **55** of the wellbore **50** as shown in **Figure 1** or to any other depth where the sensors are desired. The lower instrumentation line **12L** (shown in **Figure 1**) attaches along the length of the stinger subs **390**. The lower instrumentation line **12L** may be clamped along the outer surface of the stinger subs **390**, may dangle within a bore of the stinger **300** or dangle freely in the wellbore below the stinger subs **390**.

[0034] The connector mandrel **310** includes a milled pocket **356** and a channel **351** extending from the pocket **356**. The milled pocket **356** houses a lower

connector **370** that is connected to the lower instrumentation line **12L**. From the connector **370**, the lower instrumentation line **12L** travels through the channel **351**. The lower instrumentation line **12L** exits the channel **351** and turns back to run downward along the stinger **300**. In one arrangement, the line **12L** runs through a bore **315** (visible in the cross section views of **Figure 7** and **Figure 9**) of the stinger **300**. As illustrated in **Figure 8**, the pocket **356** of the connector mandrel **310** also receives the connector guide **278** of the landing tool **200** when the coupler is in the connected position. The pocket **356** is deep enough to permit the upper connector **270** to completely clear the inner diameter of the offset mandrel **210**. This, in turn, allows the upper connector **270** in the landing tool **200** to properly align in a radial direction with the lower connector **370** in the stinger **300** which is already aligned rotationally by the interaction of the key **388** with the orienting sleeve **280**.

[0035] Referring to **Figure 5A**, a lower end of the collet mandrel **330** defines a collet stop **334**. The collet stop **334** serves as a shoulder against which a collet **340** disposed around the collet mandrel **330** may be attached. The collet **340** has a base **344** connected to the collet stop **334** of the collet mandrel **330**. In addition, the collet **340** has a plurality of outwardly biased fingers **348**. The collet fingers **348** have an outer profile **346** that mates with a collet profile **259** (shown in **Figure 2** and **Figure 2A**) along the inner diameter of the debris sleeve **250**.

[0036] **Figure 6** illustrates an intermediate position of the coupler **100** as the stinger **300** traverses into the landing tool **200**. Visible in the enlarged views of **Figure 6A** and **Figure 6B**, the outer profile **346** along the collet fingers **348** engage the collet profile **259** along the debris sleeve **250**. Thus, axial movement of the stinger **300** transfers to the debris sleeve **250** in the landing tool **200** and shifts the debris sleeve **250** downward in order to expose the pocket **218** in the offset mandrel **210**. As shown in the intermediate position, a small portion of the debris sleeve **250** adjacent the lower end of the window **256** continues to block outward movement of the connector guide **278** and housed upper connector **270** of the landing tool **200**. Thus, the two connectors **370**, **270** are not yet aligned since the connector guide **278** for the upper instrumentation line connector **270** has not yet moved inwardly

and the key **388** has not yet seated in the bottom-out edge **288** of the orienting sleeve **280** in order to rotationally orient the lower connector of the stinger **300** when the coupler **100** is in the intermediate position as shown in **Figure 6**.

[0037] **Figure 7** is a cross-sectional view of the coupler **200** taken across **line 7-7** of **Figure 6A**. As shown, the offset mandrel **210** includes a cap **292** on one side that serves as a spring housing. The cap **292** connects to the offset mandrel **210** by one or more fasteners **294**. Also visible within the cross-sectional view of **Figure 7** is the connector guide **278** having the opening **275** for housing the connector **270**. The pin grooves **273** are seen along the connector guide **278** for receiving the pins **373** within the debris sleeve **250**. The bow spring **290** is in a compressed state, but is biased to urge the connector guide **278** inward. However, a flat surface **250'** in the debris sleeve **250** butts against the connector guide **278** and prevents the connector guide **278** from moving inward towards the center of the coupler **100** since the coupler **100** is in the intermediate position.

[0038] **Figure 8** shows the coupler **100** in the connected position. In the connected position, the landing shoulder **366** of the stinger **300** contacts or lands on the profile **236** of the landing tool **200**. As the stinger **300** moves between the intermediate position and the connected position, the bow spring **290** acts on the connector guide **278** that is no longer restrained by the debris sleeve **250** and urges the connector guide **278** inwardly towards the connector mandrel **310** of the stinger **300** such that the upper connector **270** aligns with the lower connector **370**. Further, the key **388** of the stinger contacts the shoulder **286** and rotates the stinger **300** to position the key **388** within the bottom-out edge **288**. This rotationally aligns the connectors **270, 370**. As seen in the cross section view in **Figure 9**, the pins **373** engage the grooves **273** along the connector housing **278**, further aligning the upper connector **270**.

[0039] Merely because the upper instrumentation line connector **270** has aligned with the lower instrumentation line connector **370** does not mean that communication has taken place as between the two connectors **270, 370**. For example, where the two lines **12L, 12U** are fiber optic lines, it is possible that oil

residue or debris could come between the two connectors **270**, **370**, preventing optical communication. In this instance, it is desirable to pull the stinger **300** back up within the landing tool **200** before locking the stinger **300** in the landing tool **200** and circulate a cleaning fluid through a bore of the stinger **300**. Thereafter, a reconnection can be attempted between the connectors **270**, **370**.

[0040] Once the coupler **100** is in the connected position and communication is established, the stinger **300** may be locked in the landing tool **200** with an optional latching mechanism **400** at the top of the stinger **300**. The latching mechanism allows the position of the stinger **300** to be axially locked relative to the landing tool **200** and permits release of the stinger **300** from the landing tool **200** in the event it is desired to remove the stinger **300** from the wellbore **50**. Any known releasable latching mechanism may be used between the stinger **300** and the landing tool **200** of the coupler **100**. As shown, the latching mechanism **400** includes locking dogs **426** that are selectively moved outward into the profile **226** of the landing tool **200**.

[0041] After the coupler **100** is in the connected position and when the stinger **300** is unlocked from the landing tool **200**, the stinger **300** may be raised back up within the landing tool **200**. In this manner, it is possible to return to the intermediate position shown in **Figure 6** or run-in position after placing the coupler **100** in the connected position shown in **Figure 8**. Referring to **Figure 6**, a beveled surface **357** is provided along the pocket **356** of the connector mandrel **310**. The beveled surface **357** matches a beveled surface **276** of the connector guide **278**. Thus, as the stinger **300** axially raises relative to the landing tool **200**, the beveled surface **357** of the connector mandrel **310** engages the beveled surface **276** of the connector guide **278** and urges it back outwardly towards the pocket **218** in the offset mandrel **210**. The outward force of the connector mandrel **310** on the connector guide **278** overcomes the inward force of the bow spring **290**. In this manner, the stinger **300** can be raised for circulation of cleaning fluid when attempting to establish communication or completely removed from the wellbore during well completion and remediation procedures that may damage the lower instrumentation line **12L**.

[0042] While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.